Ann. Rev. Energy 1986. 11: 209–28

CALIFORNIA'S ENERGY SUPPLY AND DEMAND IN 1984[1]

I. Y. Borg and C. K. Briggs

Lawrence Livermore National Laboratory, Livermore, California 94550

INTRODUCTION

California's energy supply and use patterns have been unique among the 50 states for decades. They reflect the indigenous oil and gas resources, the small role for coal, the size of the state and the related importance of highway vehicles, and the rapid growth in both population and share of the nation's GNP. State legislative and regulatory bodies have been quick to seek and encourage imaginative solutions to the energy crises of the 1970s. That total energy consumption in 1984 was at 1973 levels (1), despite an approximately 20% increase in population (2), suggests that conservation has been appreciable. Alternative energy sources such as solar and geothermal power, alcohol automotive fuels, and cogeneration have thrived in the state because of favorable state tax structures that have been tantamount to outright subsidies. These incentives have been in addition to support from federal sources. Both the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) have fostered conservation and made it possible for alternative forms of energy to play roles in the overall energy scheme. Many regulations and laws relating to energy have been in place for many years, and the results are now becoming clear. It is not surprising that this collective effort to deal with the limited nature of conventional energy supplies has met with success. Windpower and geothermal installations in the state are

[1] Work performed under the auspices of the US Department of Energy by the Lawrence Livermore National Laboratory under contract number W-7405-ENG-48.

now the largest in the world and continue to grow. Cogeneration in California and in Texas has no parallel in other states. However, unanticipated problems have arisen in connection with the concerted effort to find new energy sources. In addition, energy use in the state has begun to climb, erasing some of the gains of the last decade. In particular, demand for transportation fuels is on the rise again because improved vehicle mileage has been more than offset by an increase in the number of vehicles on the road. The following sections describe the contributions of both the principal new components of the state's energy slate and traditional sources that continue to supply the bulk of the energy consumed.

CALIFORNIA ENERGY SUPPLY AND DEMAND IN 1984

California's energy flow for 1984 (Figure 1) forms the backdrop for the introduction of new energy sources into the state. Despite innovations of the past ten years, the broad outline of flow does not differ substantially from that in previous years. Major features have persisted despite the shortages of the 1970s. Nonetheless, in detail numerous changes are apparent from year to year. For example, energy use in 1984 increased 5% over 1983 totals, reversing a downward trend started in 1979. Use of all fuels increased, as did consumption of electrical power. While some part of the increase can be attributed to a population increase of approximately 2%, the increase followed national trends that reflect a good economic year. The GNP (in 1972 dollars) rose 6.8% nationwide, and net farm income in constant dollars increased almost 83% following the two farm recession years of 1982 and 1983. Unemployment fell to 1981 levels, and industrial production, as measured by the Federal Reserve Board index, rose 11% over 1983 (3). Collectively this growth spelled increased energy demand in all end-use sectors. Nonetheless, the increased demand was modest in light of the large increases in most economic indicators, suggesting that conservation in all its forms continued to make inroads into energy use. In California the most impressive change was the increased use of electricity (9%), which was made possible by increased out-of-state imports (up 21%) and the addition of new nuclear capacity as well as the return to service of nuclear units down for repair.

California's energy flow continued to show marked contrast with that of the nation as a whole (4). Transportation accounted for 40% of all energy consumed in the state, compared with 27% for the nation (3). Despite mandated mileage standards for new cars, the use of transportation fuels in the state rose almost 7% over 1983. Other end-use sectors showed small declines (residential and commercial) or small increases

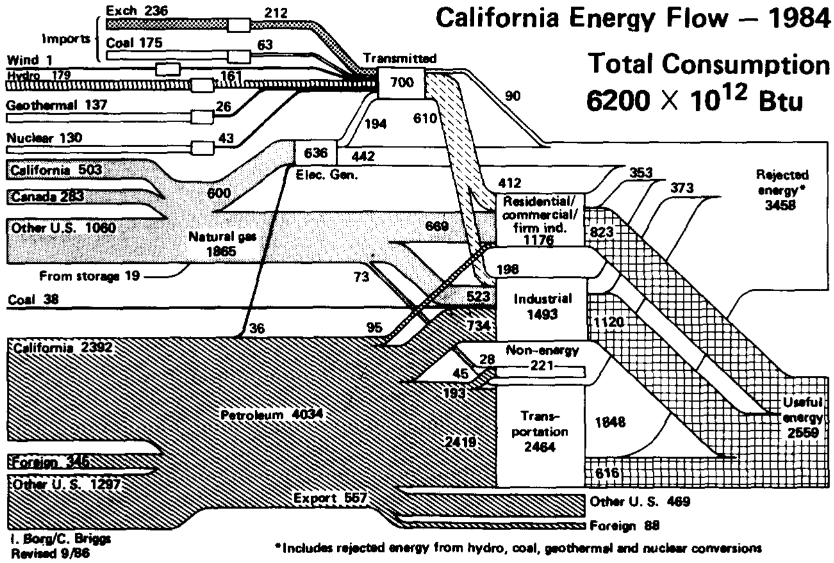

Figure 1 California energy flow for 1984. The sources of the data used to construct the chart are given in detail in Appendixes A and B, Ref. 4. The two values separated by a box associated with individual sources of electrical power (e.g. geothermal) reflect the efficiency of the conversion process. They were calculated from historical data from years when the *Quarterly Fuel and Energy Summary* published by the CEC gave primary energy input and electricity distributed for each source: hydropower, 90%; coal, 32%; geothermal, 19%; nuclear, 33%; and oil and gas, 33%. The division between "useful" and "rejected" energy is arbitrary and also depends on assumed efficiencies. In the residential and commercial end-use sectors, a 70% efficiency was assumed, which is a weighted average between space heating (60%) and electrical lighting and other electrical uses (about 90%). Seventy-five percent efficiency is assumed in the industrial sector and 25% for transportation, which corresponds to the approximate efficiency of the internal combustion engine.

(industrial). Except for coking coal, used in a small steel plant, coal is not used in the state. Coal-fired electric generating facilities, partially owned by California utilities, are located in southwestern states; their contributions are indicated as imports in Figure 1.

OIL AND GAS SUPPLY

Petroleum Production

California's petroleum production is fourth in the nation, behind those of Texas, Alaska, and Louisiana; 1984 was a record year for crude oil production in California as a result of increased production from state offshore leases and enhanced oil production.

The Point Arguello offshore field under development is the largest on the US Outer Continental Shelf (OCS). Together with the Point Pedernales offshore field discovered in 1983 and others in the prolific Santa Maria offshore basin, oil production in California is expected to continue to set offshore records to the end of the decade.

Enhanced oil production accounted for 55% of California's production; steam stimulation and water flooding represented 69% and 30% of the incremental production, respectively (5). Increasingly, natural gas is replacing oil as fuel for generating steam. Cogeneration of electricity under the Public Utilities Regulatory Policy Act of 1978 (PURPA) is an added inducement to enlarge steam recovery techniques. It is reported that oil so produced can be extracted for between $7 and $13 and sold for $20 per barrel (6). California contains three of the five largest oil fields discovered in the United States as well as the largest of the Naval Petroleum Reserves, Elk Hills. Elk Hills was the largest petroleum producer in the state until 1984, when it was overtaken by the Midway-Sunset field in Kern County. The Naval Petroleum Reserves were set up early in the century to supply oil to naval vessels that theretofore had been fueled by coal. Elk Hills saw little production until 1976 when it was reopened, the wells reworked, and the field expanded to provide a buffer for potential shortages, like those experienced in 1973–1974. Twenty percent of the land in the Reserve is owned by Chevron. Since 1977 it has been treated as a unitized field, with oil produced at maximum efficient levels. It has produced 491 million barrels since it was reopened, and in fiscal year 1984 grossed $1.4 billion for the federal treasury. It is scheduled to continue production through October 1988, at which time production policy will be reviewed by the President. Its continued production is justified on the basis of its abilities to supply oil in emergencies, avoid adverse impacts on local communities, and provide monies for other federal programs, e.g. filling of the Strategic Petroleum Reserve (SPR) [Table 1; see also (7)]. In the event that SPR purchases are curtailed as recommended by the current administration, Elk Hills' role in emergencies could be important. If it were shut in again, it would take 6–12 months to bring it back to full production. Production at Elk Hills has already begun to decline (Figure 2), and will continue to do so, although a new exploratory program targeted at deeper zones (greater than 10,000 feet) has promise of finding new producing horizons (8).

Natural Gas Supply

Despite its indigenous oil and gas production, California has depended on other states and Canada for its gas supply for decades. Currently the dependence is for about 72% of supply.

Figure 1 shows the proportion of supply coming from Canada on long-

Table 1 Comparison of oil added to the Strategic Petroleum Reserve and production at Naval Petroleum Reserve No. 1 (Elk Hills, California)[a]

Year	SPR fill (million bbl/yr)	NPR production (million bbl/yr)	Estimated reserves at year end (millions of bbl)
1974	0	0.84	1009
1975	0	0.77	1008
1976	0	11.7	996
1977	7	40.0	956
1978	60	45.2	911
1979	24	55.0	856
1980	17	58.9	930
1981	122	63.2	911
1982	64	59.8	851
1983	85	55.5	796
1984	72	49.4	746
Total (1976–1984)	451	439	

[a] Source: *Monthly Energy Rev.*, DOE/EIA-0035(85 02), February, 1985, p. 41; *Annual Reports of the California Oil and Gas Supervisor*, 1975 through 1984, Publication PR-o6, Sacramento, Calif.

term contracts via Pacific Gas Transmission Co., a Pacific Gas and Electric Company (PG&E) subsidiary; from the southwest through El Paso Natural Gas Co. lines; and from Texas in Transwestern Pipeline Co. lines. The largest share of California production is in Northern California non-associated gas fields sold to the PG&E network; however, federal OCS production from the Hondo and Pitas Point fields in recent years has made important contributions.

The state's principal gas-distributing utilities (Pacific Lighting Co., whose main subsidiary is Southern California Gas Co., and PG&E) are the two largest in the world, with well over 7 million customers. A sizable portion of the gas consumed is in electrical generation (Figure 1), which reflects the level of gas imports during the summer months when heating demand is low.

Gas supplies are expected to be adequate until the mid-1990s; however, traditional supplies from the Southwest and California are expected to drop rapidly to the year 2000 (9). Although demand is predicted to continue falling as it has for the last five years, flat or modest growth rates are expected to the turn of the century. At this point supplemental sources will be needed, and Canadian gas is the most likely source, perhaps with additional supplies from Alaska if the Alaskan North Slope Gas pipeline is constructed by that time. Other possibilities are liquefied natural gas imports from Indonesia and Cook Inlet, Alaska, as well as unconventional

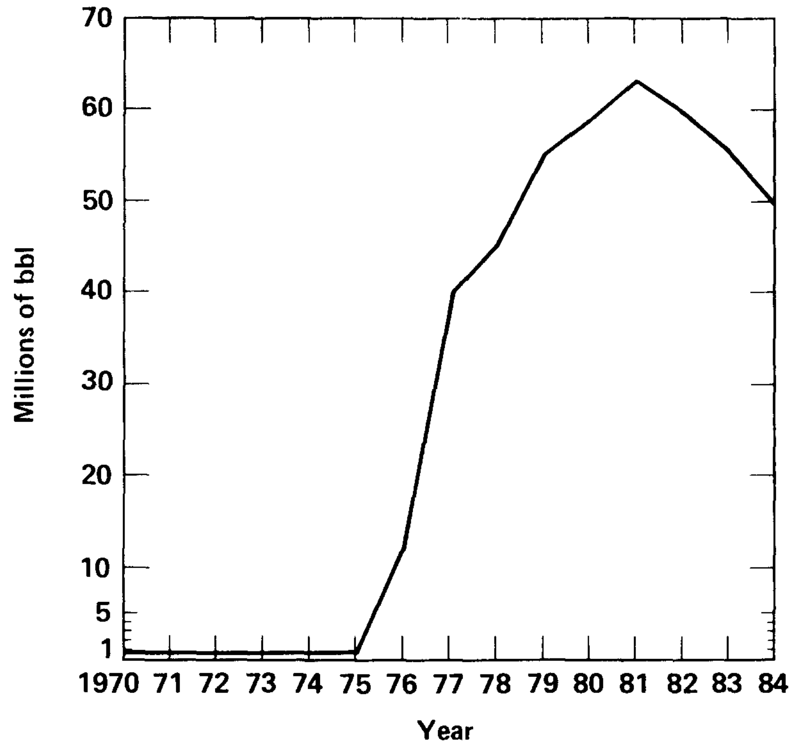

Figure 2 Elk Hills, Naval Petroleum Reserve No. 1, Kern County, oil and condensate production.

supplies, e.g. from coal gasification and heretofore unproductive tight gas sands.

ELECTRICAL POWER PRODUCTION

Electrical Exchanges

It is apparent from Figure 1 that the state receives a large portion of its transmitted power (40%) from imports from the Pacific Northwest and Pacific Southwest regions (Figure 3). Imports to California are labeled "exchange" since contracts guarantee the Pacific Northwest utilities, for example, firm winter capacity from California if needed. Nonetheless, power has moved only south since 1981. The Western Energy and Supply Transmission system, a grid that provides power to California from the southwest states, carries purchased power as well as power from out-of-state coal-fired plants that are partially owned by California utilities.

In 1964 Congress approved construction of the Pacific Northwest–Pacific Southwest interties. Three interties were constructed by California and Pacific Northwest utilities (two ac lines with 2800 MWe capacity and one dc line with 1560 MWe capacity). These interties carry power from federal hydroelectric installations, such as Bonneville Dam, as well as

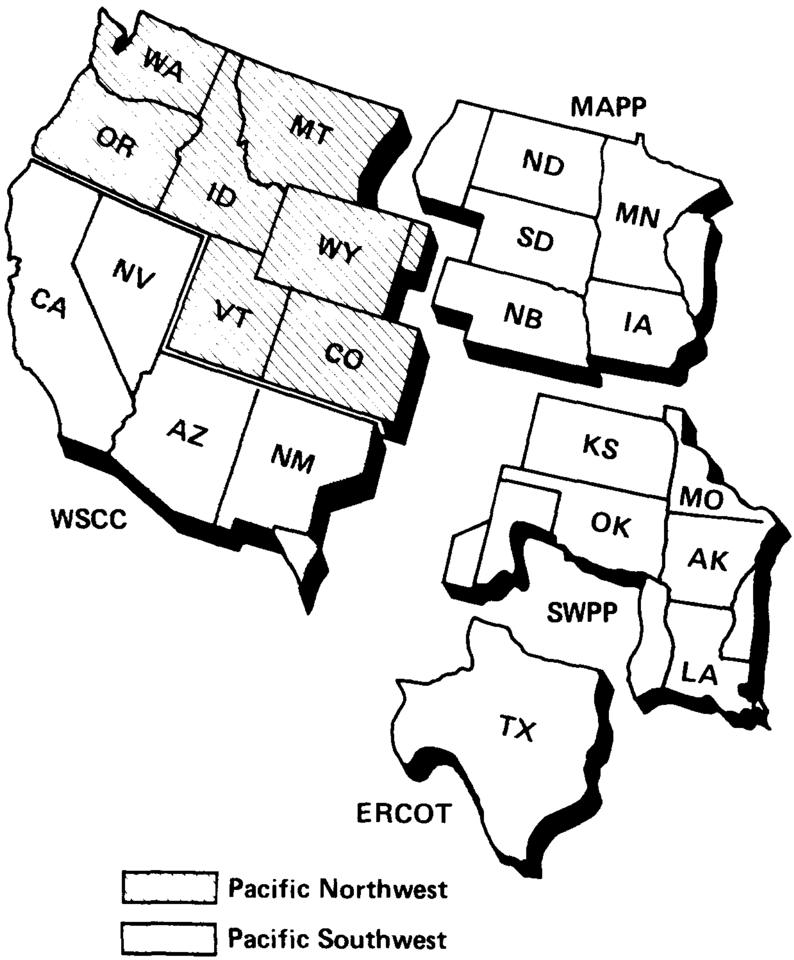

Figure 3 Regions of the North American Electric Reliability Council within the western United States. WSCC: Western Systems Coordinating Council, including Pacific Southwest (Arizona, New Mexico Power Area, and California-Southern Nevada Area) and Pacific Northwest (Northwest Power Pool Area and Rocky Mountain Power Area); ERCOT: Electric Reliability Council of Texas; SWPP: Southwest Power Pool; MAPP: Mid-Continent Area Power Pool. Source: *Interutility Bulk Power Transactions*, Washington, DC: DOE/Energy Inf. Admin. 0418 (October 1983).

surplus power from Pacific Northwest utilities and British Columbia, Canada.

In September 1984 the Bonneville Power Administration (BPA), which manages the intertie, announced a new Near Term Intertie Access Policy that allowed all Pacific Northwest utilities to sell power to California in proportion to their surpluses on hand. The policy is a reflection of the large amount of surplus power throughout the Pacific Northwest, not all of which is hydropower. For example, the Colstrip Unit 3 coal-fired plant in Montana—originally built to serve Montana, Washington, and Oregon—has so much surplus power flowing to California that the Montana Public Service Commission denied a request from the utility to pass the costs of the plant on to Montana ratepayers. Surpluses reflect overestimation of demand on the part of utilities and public agencies in both the Northwest and Southwest. The same factors led to the delays associated with the five nuclear plants planned by the Washington Public Power Supply System; of the five, BPA owns Units 1 and 2 entirely and owns 70% of Unit 3. It has been remarked that "the complex of sophisticated Western energy grids is looking more and more like a marketing arrangement for a chain of white elephants" (10).

The immediate effect of apportionment of power transfers to California is that the price of the power will vary with its source. At the same time BPA raised the price of its own nonfirm power from 1.1 cents per kWh to 1.85 cents, almost double 1983 costs. The ruling also eliminated the cost savings to California users that had stemmed from the competition between US and Canadian utilities to dispose of their surplus power in previous years.

California utilities argue that in effect they were paying for poor planning on the part of Pacific Northwest utilities and subsidizing those utilities' ratepayers, who already enjoy the lowest rates in the nation. They point out that 45% of the nonfirm rate charged them by BPA is associated with the fixed costs of the three unfinished nuclear units; that the policy will in most cases prevent Canadian power purchases; and that implementing the policy could well mean forced purchases of coal or nuclear power from one Pacific Northwest utility while another is spilling water at a hydroelectric dam.

BPA argues that power going to California has not covered the costs of generation and that California was the main beneficiary of the low electrical rates associated with the large federally financed hydroelectric plants throughout the region. The counter to the charge of poor planning by the Pacific Northwest utilities is that the same can be said for the state of California, which for decades has relied on other states to meet its growing demand. That trend may continue (11), and the state's utilities are increasingly looking beyond the borders of the nation. In 1984 San Diego Gas and Electric Co. (SDG&E) signed agreements with the Baja California Dynatek Trading Co. to supply 110 MWe from the Cerro Prieto geothermal field in Baja California, Mexico. Dynatek Trading Co. hopes to have 1000 MWe on line by the end of the decade, most of which will probably be sold in southern California.

Nuclear Power

Nuclear energy's contribution to the state's supply of electrical power tripled in 1984. This increase is impressive, but largely because it reflects the small role nuclear energy played until then. Even now nuclear energy provides less than 7% of the state's transmitted electrical power, less than half the national average percentage. Of the six nuclear plants either licensed or in some stage of licensing, only two—Rancho Seco (918 MWe) near Sacramento and San Onofre 2 (1100 MWe) at San Clemente—were operating during 1983. San Onofre 1 (436 MWe), which came on line in 1968, was down throughout 1983 for seismic upgrading. During 1984 San Onofre 1 returned to full-power operation and San Onofre 3 (1100 MWe) came on line for the first time. However, Rancho Seco operated for only half the year as a result of a series of problems including a small hydrogen explosion.

The trouble-plagued Diablo Canyon Unit 1 (1084 MWe) received its full-power operating license. By November it reached 15% power, which is the point where it generates more power than it consumes. This was the second time that Unit 1 had been licensed for operation. The low-power testing license issued in 1981 was rescinded several months later by the Nuclear Regulatory Commission (NRC) when it learned that the wrong blueprints had been used to install pipe supports for the cooling system. It was the first time a US reactor's license had been rescinded.

Including Unit 2 (1106 MWe), which is scheduled to be commercial by mid-1985, the final capital costs for Diablo Canyon are estimated at $5.4 billion, compared to the initial 1968 estimate of $430 million. The nuclear plant continued to be the center of controversy in 1984 despite its licensing because of arguments that the NRC disregarded earthquake safety issues when it granted a full-power license in 1984. In addition, PG&E's request for a rate increase to cover the costs is alleged by consumer groups to be out of order in view of the company's mismanagement.

Helms Pumped Storage

The Diablo Canyon nuclear plant and the Helms pumped storage facility represent the last of the giant power plants to be put on line in California this century. The Helms project was started in 1977 to supply peaking power so as to maintain a 5% reserve margin that was being rapidly eroded by increasing daytime loads. PG&E built a tunnel connecting two reservoirs so that water could be pumped back to the upper lake (8180 feet elevation) during "off peak" hours after release to the lower lake (6550 feet) during generation in periods of peak demand. More power is consumed pumping water back into the upper lake than is generated, and excess off-peak power from other base-load plants is used for the pumping. The mining of tunnels and the underground power house proved to be both difficult and expensive ($738 million), but within days of being placed in operation on June 30, 1984, the 1200-MWe plant was able to cope with a new record peak demand for PG&E, raising reserve margins, i.e. generating capacity, by 1%.

Cool Water Coal Gasification Project

The Cool Water project at Daggett is the first commercial-scale (120 MWe) electric power plant in the United States to burn synthetic gas from coal, and it is also the first power plant in the state to burn coal. It was built by a consortium of companies at a cost of $270 million (12). It uses Texaco's coal gasification process in a 1000-ton-per-day gasifier. Emissions are about one-tenth the levels permitted by the Environmental Protection Agency, and it uses about two-thirds the volume of water required by a similar-sized direct coal-fired plant.

ALTERNATE ENERGY TECHNOLOGIES

California boasts the nation's most aggressive state program to foster the use of alternative energy forms. In addition to experimental programs supported by the California Energy Commission (CEC), alternative energy technologies have been bolstered by favorable state tax laws. The solar tax credit of 25% of the investment can be taken over one to five years; however, the state credit is treated as taxable federal income. In addition, state depreciation schedules foster investment, namely three-year straight-line depreciation of 75% of the purchase price minus the state tax credit; or one-, three-, or five-year depreciation of 100% of the investment in lieu of the state tax credit; or three-year depreciation using the double declining-balance method on the amount of the investment that exceeds the 25% tax credit.

State and federal energy tax credits expire at the end of 1986 and 1985, respectively; the federal 10% investment tax credit will continue. As a consequence, development of alternative energy technologies and negotiation of contracts with the utilities are at an all-time high in the state.

Of equal importance are guaranteed prices under "must-take" contracts specified by PURPA. Under this act, utilities are required to purchase power from small producers at their "avoided cost." (The avoided cost is that expense the utility would incur if it built a new power plant to meet peak demand. Purchasing power from small producers obviates the need to build a new plant, hence the term avoided cost.) In California, hydropower, oil, and gas have traditionally been used for peaking, and since opportunities to increase hydropower are limited, plants that use oil and gas are the basis for avoided-cost calculations. The 1984 purchase price for on-peak power was on the order of 6–8 cents/kWh. The must-take contracts between utilities and the small energy producers run for 5–30 years, providing a stable market for the small producers.

The utilities have voiced some concern with the system. So many small producers have been attracted by the terms of the contracts, the utilities claim, that utilities are being forced to give up their cheapest sources of power for peaking (specifically, hydropower) to buy the most expensive power available under the must-take contracts. Principal sources of alternative power are, in order of importance, geothermal, cogeneration, small hydropower plants, wind, and solar. Their individual contributions to satisfying the state's power demands are usually stated in terms of installed capacity, which overstates their role. With the exception of geothermal energy, these sources are intermittent by nature and have low capacity factors, i.e. the capacity factor, as derived by the following relationship, is low: actual output in kilowatt-hours divided by the rated capacity in kilowatts, multiplied by the unit of time.

Geothermal

Installed geothermal electrical capacity in the United States (1.5 GWe) is the largest in the world. All but about 100 MWe is located in California, and until recently was centralized at The Geysers in Sonoma County. By the turn of the century an additional 1 GWe is expected to come on line at that site. To put this in perspective, the total installed electrical capacity in the state stood at 42.7 GWe, not including jointly owned, out-of-state, coal-fired plants at Four Corners, Farmington, New Mexico (1636 MWe); the Navaho Plant at Page, Arizona (2409 MWe); the Mohave Plant, Nevada (1636 MWe); the Gardner Reid Plant, Nevada (250 MWe); and the Palo Verde 1 nuclear plant, Maricopa, Arizona 1270 MWe). California utilities' share of ownership of these plants is 48% of Units 4 and 5 at Four Corners, 21.2% of Navaho, 76% of Mohave, 67.8% of Gardner Reid, and 27.4% of Palo Verde 1 (13).

Since the first 11 MWe came on line at The Geysers in September 1960, 200 wells have been drilled. By 1974, 10 of the 18 generating plants were operating, which attests to the cost effectiveness of the vapor-dominated geothermal resource before the escalation of the cost of conventional fuels. The importance of the geothermal plants in meeting growing demand for base load capacity in the state is tied to high capacity factors—70–80% (14).

In recent years major geothermal developments have used hot-water geothermal resources in other parts of the state. These are less competitive with conventional fuels for power generation, but benefit from state and federal tax incentives for alternative fuels. By 1984, three 10-MWe demonstration units in the Imperial Valley were operative, and another six plants totaling 250 MWe were under construction and due to be generating power in 1985. The 15% geothermal energy investment tax credit expired in 1985. The hot-water type of geothermal resource is typically brine-rich and requires dual flash plants or binary systems involving a second fluid that is vaporized to drive the turbines. The highly corrosive brines that are recovered must be reinjected or disposed of, adding expenses over and above plant costs.

Wind Power

At the end of 1984 installed wind power capacity in the state reached 609 MWe (Table 2). This corresponded to 8470 wind turbines at three principal locations. An additional 7000 new units had been approved at year's end, corresponding to an addition of 525 MWe of capacity. In the long term, the CEC estimates that developable wind resources could provide 6680 MWe, of which 4000 MWe would likely be developed by the year 2000 (15). To put these estimates into perspective, the CEC also estimates that by 2000 the total peak electrical demand will be approximately 47,175 MWe (16), if both market forces and conservation constrain demand. At face value this forecast anticipates that 8.5% of total demand could be met by wind power. It fails, however, to allow for the low capacity factors

Table 2 Wind power installation in California as of January 1985[a]

Location	Capacity (MWe)	Number of turbines
Altamont Pass area, 45 miles east of San Francisco	318	3900
San Gorgonio Pass, Riverside County near Palm Springs	150	2450
Tehachapi Pass, Kern County	132	1950
Mohave Desert, Kern County	7	150
Boulevard, San Diego County	4	16
Carquinez Strait, Solano County	3	10
Total	609	8470

[a] Source: Calif. Energy Commission.

associated with wind power. In 1984 California utilities purchased 195 million kWh of wind-generated power. If we assume that 1984 capacity was 450 MWe, the mean between values associated with the beginning and the end of 1984 (approximately 300 and 600 MWe), a capacity factor of 5% can be calculated for the year. It is reasonable to expect that improvements will raise this average value; however, because of the diurnal and seasonal aspects of wind power (Figure 4), it is unlikely that in many areas capacity factors can appreciate materially. The Tehachapi Pass area may be an exception, since this area in southern California experiences moderate, year-round winds with minimal diurnal fluctuation. Here factors could perhaps reach 60–70%. The largest developed area, the Altamont, 45 miles east of San Francisco, generated 125 million kWh in 1984 at an estimated 13% capacity factor (17).

Performance factors will also improve as optimum turbine designs for

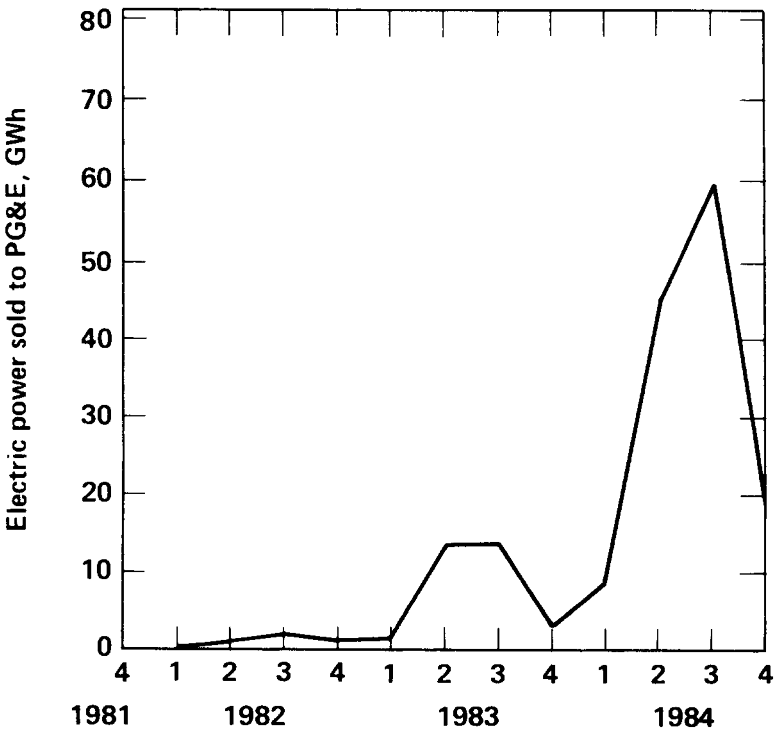

Figure 4 Amount of wind-produced electricity sold to PG&E from 1982 through 1984. The substantial increase reflects the increasing number of windmills and a two- to threefold increase in performance factors. Source: D. Smith, consultant, PG&E, San Francisco, California, personal communication, February 11, 1985.

given areas are developed and installed. The performance factor is a measure of the output compared to what is possible at that site. Hence it takes account of turbine performance and durability as well as actual wind velocities, distribution, duration, and variability. In September 1984 performance factors were calculated to be 76% in the Altamont area (17). The substantial increase in output shown in Figure 4 reflects not only the increasing numbers of windmills installed, but also two- and threefold increases in performance factors (17).

The usual wind farm consists of 100-kW units whose blades are located downwind of the turbines. Most of the Darrieus or "egg beater" turbines are rated at 170 kW, with some as large as 300 kW. There are several experimental machines in the state. PG&E built a 200-foot-tall machine with a blade-swing diameter of 300 feet. It is rated at 2.5 MWe capacity, and by mid-1984 it had produced more than 2.1 million kWh of electricity, corresponding to a 5% capacity factor since it began operating in July 1982. Another demonstration project funded by Southern California Edison Company (SCE) at San Gorgonio Pass is a 1.3-MWe Bendix/Schachle wind turbine. It is 191 feet high, and its three blades sweep an area 165 feet in diameter; it is expected to produce 3 million kWh annually.

In 1984 the utilities paid between 6 and 8 cents/kWh for on-peak power, based on the avoided cost of oil-fired power generation (18). Wind energy costs are reported to be 12.6 cents/kWh (17, 19), almost double the peak-power price paid by the utilities. These costs were based on 2% operating and maintenance costs, 20% fixed charges for capital, an installed capacity cost of approximately $1500/kW, and a 30% capacity factor. The latter is an optimistic estimate and probably a maximum for future operations. Thus, windmills are not profitable at present without state and federal tax advantages and without the "must-take" contracts with the utilities; however, profit margins will increase if capital costs can be reduced and if power-generating efficiencies and equipment reliabilities improve. The capital cost for a kilowatt of capacity had already decreased from $2200 in 1981 to $1500 in early 1985 (20).

An important aspect of wind power is that in many areas—e.g. the Altamont—maximum output nearly coincides with periods of peak demand, namely in the late afternoon and in the summer and autumn. Since owning and operating conventional power plants in a stand-by mode to meet peak demand will continue to be very expensive, wind power may well be able to play an important role in California. Although it does not appear that the federal and state tax credits will be extended beyond their 1985–1986 expiration dates, standard depreciation procedures and investment tax credits will continue, as will "must-take" contracts that guarantee purchase of electricity at avoided costs. These, in conjunction with expected reduced capital and operating costs and higher avoided costs associated with likely increases in the cost of conventional fuels, may be sufficient to attract investors and sustain what has been a phenomenal growth in the state.

Cogeneration

California, like the United States as a whole, is experiencing rapid growth in power available from cogeneration facilities. Almost 1% of the power generated in the state in 1984 was from cogeneration. In Figure 1 the 3×10^{12} Btu of cogenerated power is included in oil and gas associated with electricity generation. There are hundreds of cogenerating plants in the state and even more in the planning or development stage. California utilities in early 1985 had signed contracts for 15 GWe of cogenerated power. Approximately two-thirds of cogeneration plants are fueled by natural gas (21).

Cogeneration is of primary interest to energy-intensive industries such as oil refining, enhanced oil recovery (steam generation), and food processing, all of which are important in the state. Until recently California public utilities have not objected to the dictates of PURPA, which has encouraged the use of unconventional fuels and cogeneration. New record demands on the state utilities have been set yearly; without San Onofre nuclear plants during the 1984 summer heat wave, reserve margins would have been dangerously low.

Nonetheless the flood of proposed cogeneration plants by 1985 was beginning to saturate the market. Many of these plants are in the hundred-megawatt size range, e.g. the 300-MWe enhanced oil recovery plant built by Texaco in Kern County, a development probably not envisioned by either the California Public Utilities Commission (CPUC) or the authors of PURPA. The generous avoided-cost provisions were tied until mid-1985 to the price of natural gas, and there was some concern that the cogenerating plants were much larger than needed and built solely for the profit to be gained by selling the power to the local grid (22). The cogeneration market will continue to grow in the state, partly because of a perceived surplus of natural gas during certain times of the year and because even without heretofore very profitable sales to utilities, the projects stand on their own merits.

Solar Energy

Solar hot water units are commonplace throughout the state. Their collective importance to the state's energy picture is hard to assess, but it is not negligible. More conspicuous are the several large solar power plants that began full-time operation in 1984. The largest is Solar One, a 10-MWe "power tower" in the Mojave Desert jointly funded by SCE, the Los

Angeles Department of Water and Power, and the US Department of Energy (DOE). The sun's energy is focused by 1818 heliostats on a boiler atop a 300-foot tower. It started up in 1982 at a cost of $141 million. Technical problems related to diurnal thermal cycling were solved by using approximately 18% of the power generated to keep the equipment warm overnight. Deterioration of the mirrors' reflectivity at the rate of 8% monthly has been mitigated by washing them down periodically. It is expected to supply as much as 600 MWh monthly to the local grid (23).

Another large plant, located near Warner Springs, California, is Solarplant One (4.92 MWe). It was built by private investors and sold its first power to SDG&E in 1984 (24). It uses 700 parabolic-dish solar concentrators. Operations, including tracking the sun, are computer controlled. Lajet Energy Company, the principal participant, estimates the capital cost at about $4790 per kW, and believes that ultimately costs will decline so that the system can compete with conventional power plants.

A third solar plant began generating electricity for the Sacramento Municipal Utility District (SMUD). The 1-MWe plant consists of 896 photovoltaic panels, covers 10 acres, and is the first of five units designed to produce 100 MWe by 1993. Ultimately the five units will cover 1000 acres (25). The first phase, costing $12 million, was funded by SMUD ($3.12 million), DOE ($6.8 million), and the CEC ($2 million). These three plants augment existing solar plants in the state—Arco Solar at Hesperia (1 MWe) and Arco Solar at Carrisa Plain (4.5 MWe)—that are currently selling power to local utilities. Total installed solar capacity exceeds 21 MWe. Costs for the demonstration plants are $12,000 to 14,000/kW, but larger units using similar technologies are expected to bring costs down to $3200 to $4000/kW. Success with a demonstration 48-MWe solar pond announced by SCE may bring solar costs down even further. The solar pond technology uses solar-heated salt water, heat exchangers, and a Rankine-cycle turbine to generate electricity with technology developed at two sites in Israel.

In summary, California continues to lead the nation in solar installations. Demonstration plants have been expensive, and funding for larger units in an era of falling energy prices has become difficult.

Methanol Fuel Program

In recognition of the state's large and growing need for transportation fuels, for the past six years the CEC has mounted demonstration programs and urged use of methanol as vehicle fuel. The state has provided incentives for vehicle conversions by allowing tax credits and equalized fuel taxes on methanol by basing them on a Btu basis rather than on the usual volumetric basis used for gasoline. The state has approved measures to acquire a 1000-

car methanol-fueled fleet complete with requisite fueling and maintenance facilities. By 1984, the state-maintained fleet consisted of 540 Ford Escorts modified to use a mixture of 90% methanol and 10% unleaded gas. These vehicles cost about $2000 more than the standard models, but the differential should decrease as the number of vehicles manufactured increases. The advantages, apart from mitigating the demand for petroleum-refined products, include increased engine efficiency and lowered NO_x and CO emissions. Assessment of the environmental consequences of emissions associated with use of methanol (e.g. unburned fuel and aldehydes) have yet to be made. They may require engine modifications or addition of abatement equipment, but problems at this juncture do not appear to be insurmountable. In addition to demonstrations involving standard passenger cars, the CEC is funding a one-year methanol bus program involving two General Motors and two Maschinenfabrik-Augsburg Nurnberg (M.A.N.) coaches in use in the service area of the Golden Gate Transit District (26).

Another experiment in the use of methanol vehicles is sponsored by the Bank of America. The bank has tested and operated a fleet of 266 "neat-fueled" Ford and GM vehicles in the state (27). By the bank's account they have performed well while covering more than 7 million miles, and the methanol fuel could be cost-competitive with gasoline with some additional improvements in efficiency [Table 3; see also (28)].

Although methanol is the only fuel that has promise of supplanting gasoline as a vehicle fuel, its availability is currently limited, and there is no distribution system except for small fleets. State subsidies and tax credits may be forthcoming, but substantial use of methanol ultimately rests on economic factors, the most important of which are the costs of the fuel, retrofitting, and the distribution system. Feedstock produced from underground coal gasification holds promise of lowering the cost of the fuel (29); however, in the foreseeable future, gasoline will remain the chief vehicle fuel.

PROGNOSIS FOR THE FUTURE

Except in electric power production, the role to be played by conventional fuels in California can be predicted with some certainty. Natural gas, mainly from out-of-state sources, will continue for the next several decades to be consumed by residential, commercial, and industrial end-users. Oil, more than half of which comes from local production, will continue to dominate the state's energy flow since it is used primarily by highway vehicles, which by virtue of an increasing population will increase in number. The transportation end-use sector remains the state's Achilles heel since there is little prospect of alternative fuels such as methanol and

Table 3 Theoretical comparison of fuel costs and uses of methanol and gasoline vehicles[a]

Parameter	Gasoline vehicle	Bank of America fleet, 1983[b] (GM-Citation)	Methanol vehicle with 85% technical efficiency improvement[c]
Fuel cost (incl. tax[d] ($/gal)	1.38	1.20	0.85
Miles/gal fuel	25.0	14.5	20.8
Miles/million Btu[e]	216.6	238	367.8
Btu/mile	5950	4210	2720
Cost/22-gal tank of fuel ($)	30.36	26.40	18.70
Total annual fuel cost ($)[f]	552	828	408

[a] Source: (29).
[b] Source: (28).
[c] Assume 1.2 gal of methanol provides service equivalent to 1 gal of gasoline, based on Bank of America's reported efficiency improvements.
[d] Assume $0.20/gal in state and federal tax on both gasoline and methanol, based on average tax on gasoline, 1983. Such volumetric taxes discriminate against methanol because of its comparatively lower energy content per gallon.
[e] Based on 115,400 Btu/gal for gasoline and 61,000 Btu/gal methanol 88% fuel used by Bank of America.
[f] Based on mileage of 10,000 miles/year.

battery-operated cars becoming important soon. However, price-driven conservation will make inroads into demand for oil and gas in the long term as the nation's and the world's supplies near depletion in the next century.

Alternative energy technologies are having their greatest impact on sources of electrical power. Installed capacity in the state is approximately 43 GWe including contributions from alternative sources such as wind power and geothermal energy. Another 2.5 GWe of capacity currently is in the form of out-of-state base load plants that are partially owned by California utilities. In view of long lead times associated with nuclear plants, no new plants are likely to go on line by the end of the century; thus, installed nuclear capacity in the state should remain at its current peak of 5.7 GWe, reached when Diablo Canyon 2 came to full power in 1985. Any increased capacity will be from cogeneration facilities, which have a potential of reaching 25 GWe; geothermal plants, which could increase to 2.4 GWe from 1.4 GWe today; and wind power, which conceivably could reach 3.4 GWe. The largest use of solar energy is likely to be in hot water production; as a source of electricity it will make only a small contribution.

While additional anticipated capacity seems more than adequate to meet future needs, many of the alternative sources are of questionable reliability. The financial viability of projects supplying the energy is tied to generous state and federal tax laws that are likely to be revised if not eliminated in the future. Capacity factors associated with some sources, e.g. wind power, are not high, although power generated from geothermal energy is a clear exception. The state will probably continue to rely on electrical exchanges from other states to meet demand.

Power from cogeneration poses the largest problem for both state and utility planners. As noted, its potential is enormous; however, in the end it is tied to the availability of natural gas and to a lesser extent oil, particularly heavy oil. To predict cogeneration's contribution to electricity production for the next several decades, assumptions have to be made about the long-term availability of fuels imported to the state, such as natural gas, a premium fuel that will be reserved for high-priority users if in short supply.

Literature Cited

1. Behrin, E., Cooper, R. L. 1976. *California Energy Outlook*. Rep. No. UCRL-51966, Rev. 1. Livermore, Calif: Lawrence Livermore Natl. Lab.
2. Dept. of Finance, State of Calif. 1984. *California Statistical Abstract, 1984*. Sacramento: State of Calif.
3. Briggs, C. K., Borg, I. Y. 1985. *U.S. Energy Flow—1984*, Rep. No. UCID-19227-44. Livermore, Calif: Lawrence Livermore Natl. Lab.
4. Borg, I. Y., Briggs, C. K. 1985. Singular energy trends in California. *Energy* 10(11): 1185
5. Calif. Dept. of Conservation, Division of Oil and Gas. 1985. *70th Annual Report to the State Oil and Gas Supervisor, 1984*. Pub. No. Pro6. Sacramento: State of Calif.
6. McCormack, R. September 23, 1985. California setting new oil production records every month. *The Energy Daily* 13(182): 2
7. US Dept. Energy. 1984. *Investigation on the Continued Production of the Naval Petroleum Reserves Beyond April 15, 1985*. Rep. No. DOE/FE-0043, Washington, DC
8. Maize, K. June 13, 1985. Second time luckier? DOE hopes to find more oil and gas at Elks Hill Field. *The Energy Daily* 13(113): 4
9. Calif. Public Utilities Commission. 1984. *1984 California Gas Report*. San Francisco: Calif. Public Utilities Commission
10. Gottlieb, B., Wiley, P. August 14, 1984. West's energy grid faltering. *The Oregonian*
11. Calif. Energy Commission. 1985. *The 1985 California Electricity*. Rep. No. P106-85-001. Sacramento: State of Calif.
12. Benjamin, M. R. January 12, 1984. Uncle Sam tries to get synfuels industry to bloom in the desert. *The Washington Post*, p. A-3
13. US Dept. Energy. 1982 and 1985. *Inventory of Power Plants in the United States*. Rep. Nos. DOE/EIA-0095(81) and DOE/EIA-0095(84). Washington, DC: Energy Inf. Admin.
14. Calif. Energy Commission. 1985. See Ref. 11, p. 29
15. Calif. Energy Commission. 1984. *Wind Energy—Investing in Our Future*. Sacramento: State of Calif.
16. Calif. Energy Commission. 1985. *Back to Basics: Affordable Electricity in an Uncertain World*. Rep. No. P106-85-001. Sacramento: State of Calif.
17. Smith, D. R. 1984. *Status of the 220 Megawatt Altamont Windpower Plant*. Rep. No. 007/1-84-12. San Francisco: Pacific Gas and Electric Co.
18. Solomon, B. February 19, 1985. Windmills close the gap. *The Energy Daily* 13(33): 4
19. Murray, T. J. July 1983. Money in the wind. *Duns Business Month*, p. 60
20. Solomon, B. April 26, 1985. Paradise

lost in California. *The Energy Daily* 13(80): 1

21. California cogeneration on the rise, March 25, 1985. *Oil and Gas J.* 83: 56
22. Myers, R. September 17, 1985. Cogeneration: after PURPA, the deluge. . . . *The Energy Daily* 13(178): 1
23. SoCal Edison puts Solar One on line full time, August 29, 1984. *The Energy Daily* 12(168): 1
24. California solar units back out hydrocarbons, Oct. 22, 1984. *Oil and Gas J.* 82: 81
25. SMUD opens one megawatt solar plant. July 13, 1984. *The Energy Daily* 12(135): 4
26. Jackson, M. D., Unnasch, S., Sullivan, C., Renner, R. A. 1985. Transit bus operation with methanol fuel. *California Energy Commission News and Comment* 17: 11–15
27. Bank of America Corp. 1983. *Vehicle Conversion and Methanol Fuel Program, 1980–82*. San Francisco: Bank of America
28. US Gen. Account. Office. 1983. *Removing Barriers to the Market Penetration of Methanol Fuels*. Rep. No. GAO/RCED-84-36. Washington, DC
29. Stephens, D. R., Hill, R. W., Borg, I. Y. 1985. Status of underground coal gasification. *Mineral Processing and Technol. Rev.* 1: 265–96